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Guidance Document on Evaluation of Injection Well Manifold Monitoring Systems

Woodward-Clyde Consultants, Englewood, CO

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In the Underground Injection Control (UIC) Regulations, owners and operators of Class II hydrocarbon storage and enhanced recovery wells are allowed to monitor injection pressure, flow rate, cumulative volume and the nature of the injected fluids on a field/project basis rather than on an individual well basis through the use of manifold monitoring (40 CFR Section 146.23(b)(5)). Such a monitoring system may be used in cases of operation consisting of multiple injection facilities operating with a common manifold. Separate monitoring systems for each well would not be required provided that the owner/operator demonstrates to EPA's satisfaction that manifold monitoring is comparable to individual well monitoring. The purpose of this document is to develop technical guidance and ancillary criteria to enable EPA personnel to evaluate the effectiveness of such system proposals in meeting the regulatory requirements.

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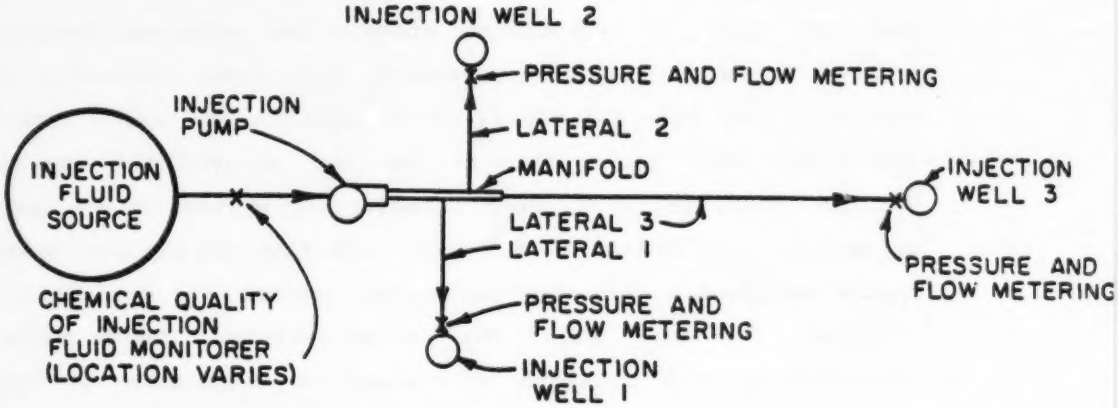
1.0 INTRODUCTION

1.1 PURPOSE OF THIS DOCUMENT

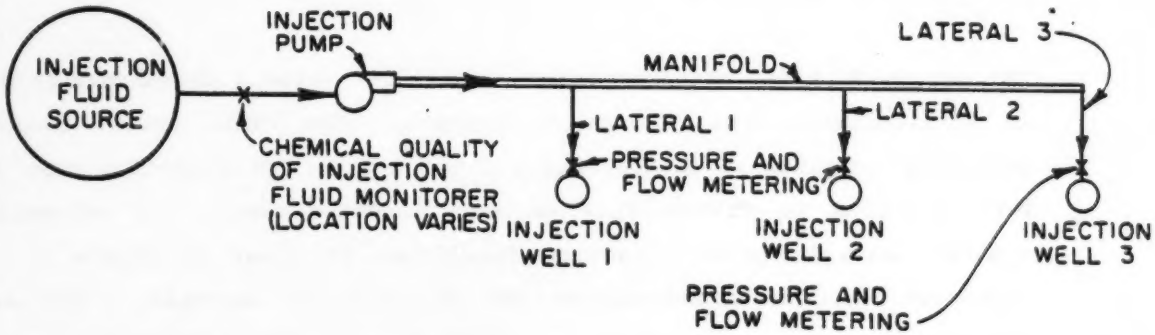
In the Underground Injection Control (UIC) regulations, owners and operators of Class II hydrocarbon storage and enhanced recovery wells are allowed to monitor injection pressure, flow rate, cumulative volume and the nature of the injected fluids on a field/project basis rather than on an individual well basis through the use of manifold monitoring (40 CFR Section 146.23 [b][5]). Such a monitoring system may be used in cases of operations consisting of multiple injection facilities operating with a common manifold. Separate monitoring systems for each well would not be required provided that the owner/operator demonstrates to EPA's satisfaction that manifold monitoring is comparable to individual well monitoring. The purpose of this document is to develop technical guidance and ancillary criteria to enable EPA personnel to evaluate the effectiveness of such system proposals in meeting the regulatory requirements.

1.2 MANIFOLD MONITORING

The use of multiple point injection facilities using a common manifold vary in configuration from project to project. The basic system components generally consists of an injection fluid source, an injection pump and a pipe manifold to divide flow to each injection well. A schematic of typical multiple point injection facilities is given on Figure 1. Each injection well is connected to the manifold by laterals. The entire manifold may in some cases be located near the injection pump with relatively long laterals to each injection well (Figure 1A). In other cases the manifold may extend out to each injection well with relatively short laterals (Figure 1B).



(A) SHORT MANIFOLD



(B) LONG MANIFOLD

MANIFOLD MONITORING SYSTEM WITH INDIVIDUAL WELL METERING

FIG. 1

Monitoring of injection pressure, flow rate, cumulative volume and the nature of injected fluids on an individual well basis requires that instrumentation for each parameter measured be provided on the lateral pipe to each well, usually located at the well head. The nature of injected fluids may be measured at any practical point in the system since no change in the nature of injected fluids would be anticipated between the pump and the injection well head.

Manifold monitoring of the injection pressure, flow rate, cumulative volume and nature of injected fluid on a project basis would be done at a central point upstream of the first injection well and downstream of the injection pump (Figure 2). A central monitoring point will reduce project cost of purchasing, operating and maintaining monitoring equipment.

2.0 STATE OF THE ART OF EXISTING MANIFOLD MONITORING SYSTEM

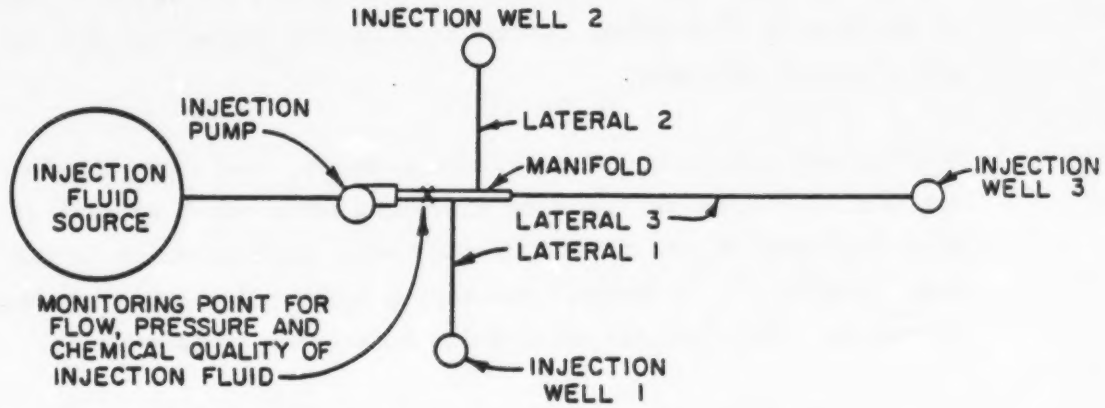
2.1 GENERAL

The use of pipe manifolds for dividing and combining flows of liquids or gases are found in many applications in industries today. Examples of manifolds used in combining flows include:

(a) Multiple pumps discharging to a single manifold;
(b) Exhaust manifolds on cars;
(c) Oilfield collection manifolds.

Manifolds have also found many applications in dividing flows, they include:

(a) Sprinkler irrigation systems;
(b) Underwater sewage discharge manifolds;
(c) Water and waste treatment flows into basins;
(d) Tailing slurry deposition systems for mining operations;
(e) Enhanced oil recovery.



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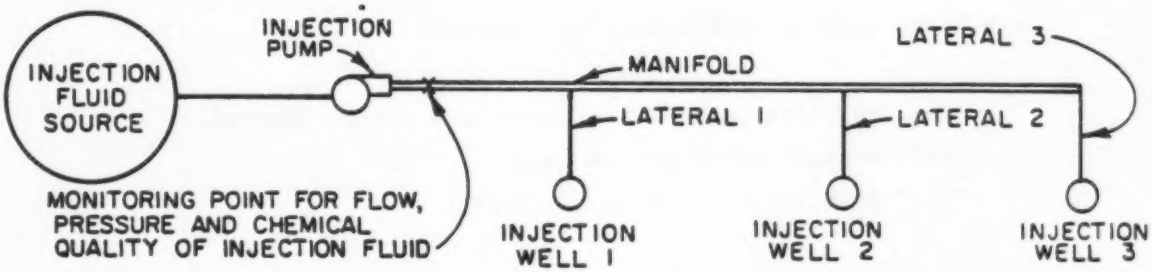


(B) LONG MANIFOLD

MANIFOLD MONITORING SYSTEM WITHOUT INDIVIDUAL WELL METERING

FIG. 2

Since the injection well systems divide flow, we have limited our scope to monitoring of divided flow manifolds.

The conclusions we drew from our literature review were that manifold monitoring generally is undertaken as a means of obtaining data on total system performance, typically total discharge. We did not locate a source that suggested manifold monitoring was or could be used to provide flow and pressure data on individual lateral lines.

Our review suggested that flow and pressure at discharge points on laterals were estimated during the design process. The design of an irrigation system for example is based on various assumptions, two of which are that flow is constant or steady state and discharge is to the atmosphere. These assumptions provide a means of estimating the flow to any sprinkler given system data which is readily available and constant with time. Examples of such data include pipe lengths, material of contruction and sprinkler head elevation. Without these assumptions, flow to individual sprinklers could not be estimated with any degree of accuracy.

Manifold monitoring systems, in general, are used to insure that required pressures and flows designed into the systems are maintained for proper operation. Typically, the ability to visually determine if the particular system is operating properly also exists. If problems develop with a sprinkler system, visual indicators generally exist. For example, if a leak in a lateral were to develop, flow may stop from the sprinkler head or a wet spot may develop on the surface of the ground for a buried lateral. If a sprinkler becomes blocked, again flow stops from the sprinkler head, thus indicating a problem. In most other manifold systems, similar types of indicators exist, thus the need to estimate flow and pressure at the discharge end of a lateral generally is not necessary.

2.2 INJECTION WELLS MONITORING

Typically, in current oil field practice, monitoring of multiple point injection systems is performed on an individual well basis. Most enhanced recovery injection projects are monitored in this manner. The monitoring systems generally measure pressure and flow at each well head. Injected flow volume is either estimated from continuous flow records (flow rate chart records) or by use of positive displacement type flow meters which operate on a cumulative volume basis. In later discussions in this document, flow rate and volume measurements are considered as basically equivalent since the output from either can be integrated over time or divided by time to get from flow rate to volume and vice versa. In addition to monitoring at the well head, flow measuring devices are in some cases installed on the manifold just downstream of the injection pump and upstream of the first injection well lateral. A configuration such as this provides a means of checking the cumulative total to the individual wells. If significant differences are noted, steps can be taken to determine the problem causing the differences.

The installation of a manifold meter to measure total flow to all injection wells seems to be related to the complexity of the reservoir system and operating expenses associated with injection fluid. Complex reservoirs using expensive injection fluids are the types of operations where a manifold meter would be utilized as a system check.

The flow and pressure measuring devices currently in use in manifold monitoring for enhanced recovery injections wells vary from system to system. The economics of the enhanced recovery operation generally influence the sophistication of the monitoring system and the metering devices used.

2.2.1 Flow Metering - General

Modern flow measurement devices commonly found in enhanced recovery injection well systems are generally either pressure differential meters or rotating mechanical meters. The pressure differential type flow meter is generally used in applications where injection rates are large; however, it is also suitable for small injection operations.

2.2.2 Pressure Differential Meters

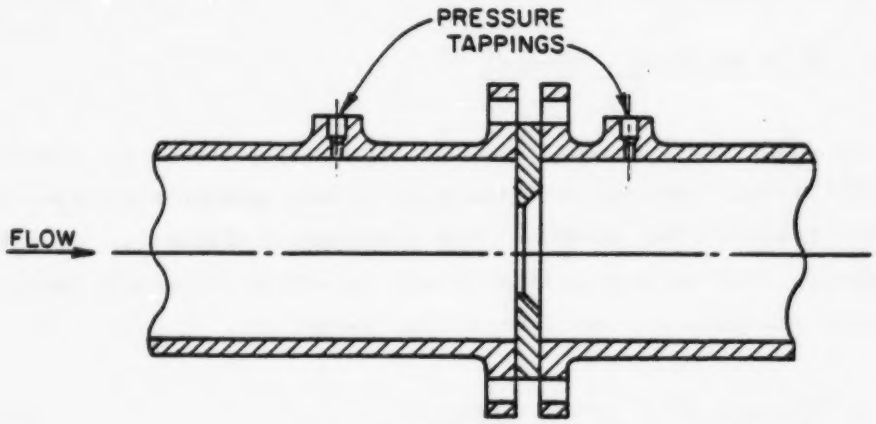
The pressure differential meter was for many years the only device available for measuring volumetric flow rate in pipes with a reasonable degree of accuracy. The most common types of pressure differential meters are the orifice meter, venturi meter and nozzle meter (Figure 3).

Each of these meters imposes a constriction to flow in a pipe. As flow moves through a constriction it accelerates causing an increase in kinetic energy and a corresponding decrease in pressure in accordance with the principle of conservation of energy. For the differential meter shown in Figure 4, flow passes through Section 1 of diameter d_1 and area A_1, at average velocity $\bar{V}_1$; then passes through section 2, of diameter d_2 and area A_2, at average velocity $\bar{V}_2$. By applying Bernoulli's equation and the principle of continuity, it can be shown that:

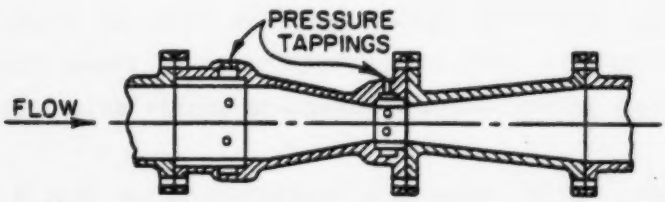
$$Q = CA_2 \quad 2g(P_1/w - P_2/w)$$

where Q = discharge, C = a coefficient, A_2 = the area of the constriction, P_1 and P_2 = pressure in pipe at Sections 1 and 2, w = unit weight of flowing fluid and g = acceleration due to gravity. The value of C varies for the different differential flow meters.

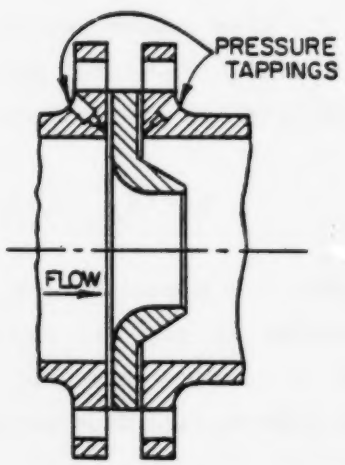
Accuracy of a differential pressure flow meter ranges from about ±1 percent if calibrated to about ±2 or 3 percent if uncalibrated.



(A) ORIFICE



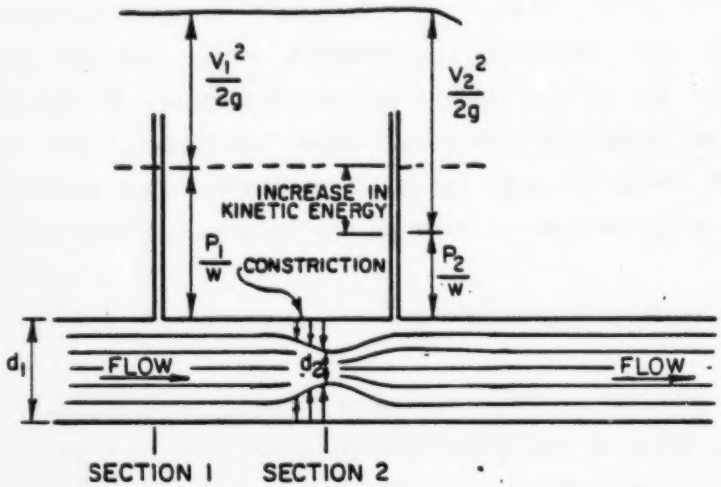
(B) VENTURI



(C) NOZZLE

THREE COMMON PRESSURE DIFFERENTIAL FLOW METERS

FIG. 3



LEGEND

V_1 AND V_2 = VELOCITY

P_1 AND P_2 = PRESSURE

W = UNIT WEIGHT OF FLUID

g = VELOCITY DUE TO ACCELERATION

NOTE: CONSTRICTION IS SCHEMATIC AND WILL VARY DEPENDING ON THE TYPE FLOW METER.

SCHEMATIC OF PRESSURE DIFFERENTIAL FLOW METER

FIG. 4

The orifice meter seems to be the most popular of the pressure differential type meters. This is in part due to the low purchase price and low installation cost. The orifice meter does have higher head loss than the venturi or nozzle type meters which would result in higher pumping cost over the long run. Discussions of additional types of flow meters is given in Appendix A.

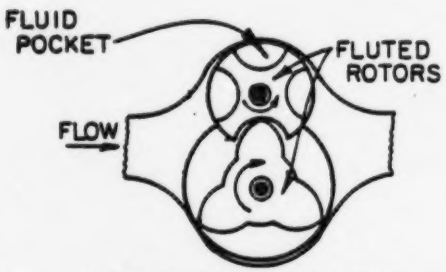
2.2.3 Rotating Mechanical Meters

The rotating mechanical meters most commonly used in measuring injection fluid flow are the positive displacement meter and the turbine meter. Although its use is not any longer as common because of the development of the two types of rotating mechanical meters mentioned above, the disc type meter is still found on many injection systems. The rotating mechanical meter measures total volume of flow or the volumetric flow rate.

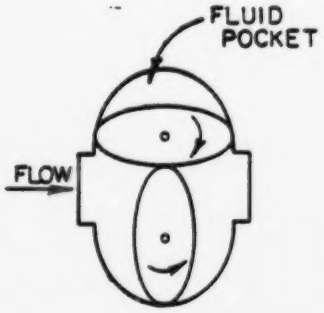
2.2.3.1 Positive Displacement Meters.

Many types of positive displacement meters are available. These meters fill the entire bore of the pipe through which flow is being measured. The meter operates by separating the flow stream into pockets of known volume and counting the number of pockets. The total number of pockets passing the meter is accumulated either mechanically or in more modern installation using digital readout equipment. Three common types of positive displacement meters are the gear meter, oval wheel meter and the sliding vane meter (Figure 5). The oval wheel is a type of gear meter.

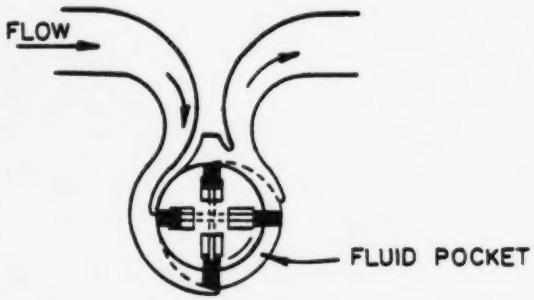
Positive displacement meters are relatively accurate for a wide range of flow rates, viscosity, pressure and temperature. Meter range is commonly from 20:1 with accuracies of better than ±0.5 percent. Positive displacement meters are generally most efficient for measuring flows and volume on the order of 1000 to 30,000 barrel per day (bbl/day).



(a) ONE TYPE OF GEAR METER



(b) "OVAL-WHEEL" TYPE OF GEAR METER



(c) SLIDING-VANE METER

SCHEMATIC OF THREE TYPES OF POSITIVE DISPLACEMENT METERS

FIG. 5

2.2.3.2 Turbine Meter

The turbine meter is another type of rotating mechanical flow meter (Figure 6). It consists of a short section of pipe in which a freely spinning propeller is mounted. The propeller blade or an insert to the propeller blade is a magnet. As flow pass through the section of pipe, it rotates the propeller blade which generates a pulse as it passes a pickup mounted in the wall of the pipe. The pickup is connected to a counter which records the number of pulses and thus the volume of flow which has passed the meter. The frequency of pulses is an indicator of volumetric flow rate passing the turbine meter.

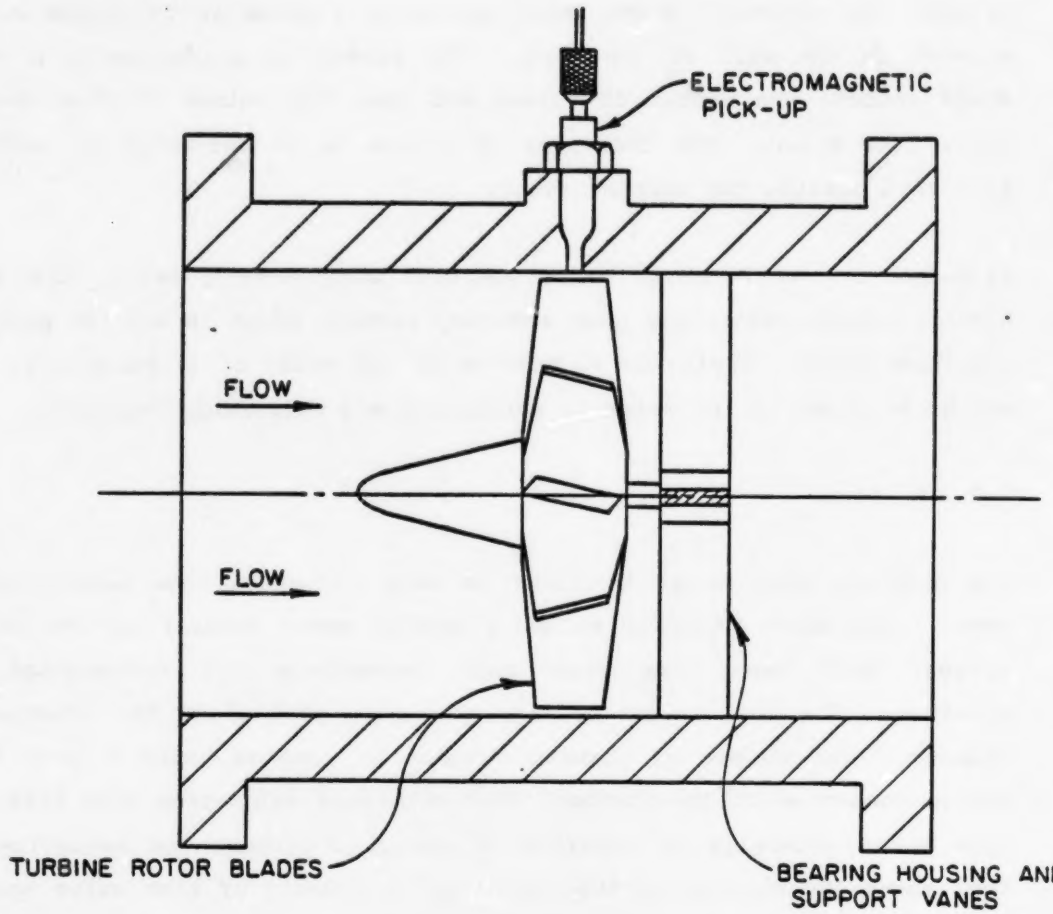
Although not as accurate as a positive displacement meter, the turbine meter provides relatively good accuracy between about 10 and 100 percent of its flow range. Typically accuracies on the order of ±1 percent or better may be achieved if the meter is maintained and calibrated regularly.

2.2.3.3 Disc

The nutating disc meter is found on many injection flow monitoring systems. Sometimes referred to as a wobble meter because of its nutating action, this meter has been used extensively for residential water metering. The flow stream is separated into pockets by the nutating disc chamber. The number of chamber volumes is counted using a gear linking system connected to the chamber, thus obtaining volumetric flow rate. This type meter generally is accurate to about ±2 percent for measuring flows from about 100 bbl/day to 5000 bbl/day. A summary of flow meter operating characteristics is given on Table 1.

2.2.4 Pressure Metering

Common types of pressure meters in use with enhanced recovery injection wells are the Bourdon Gauge and the pressure transducer. The Bourdon Gauge is the most common of these pressure measuring devices.



SCHEMATIC OF TYPICAL
TURBINE FLOW METER

FIG. 6

2.2.4.1 Bourdon Gauges

A normal Bourdon gauge consists of a metal tube with an oval cross-section formed into a semicircular shape. Generally the inside of the tube is connected to the source of pressure to be measured with the exterior exposed to atmospheric pressure. When the pressure on the inside of the tube is greater than that on the outside, the tube tends to straighten. The amount of straightening is a function of the difference between the inside and outside pressure on the tube. The tube is connected by a linkage system which converts deflection of the tube rotation of a dial. The accuracy of the bourdon tube pressure gauge is on the order of ±3 percent or better.

2.2.4.2 Transducers

The transducer type of pressure sensing device consists of a metal diaphragm connected to the pressure source to be measured. The pressure on the diaphragm causes a deflection which is proportional to the pressure. Deflection of the diaphragm is monitored by a strain gauge or variable capacitance device which produces an electrical analogue proportional to the pressure. The accuracy of this type of gauge is on the order of ±1 percent or better. A summary of pressure gauge operating characteristics are given on Table 1.

3.0 INDIVIDUAL WELL MONITORING VS. MANIFOLD MONITORING

3.1 INTRODUCTION

The following section addresses the viability of manifold monitoring of injection pressure, flow rate, cumulative volume, and nature of injected fluids as compared to the adequacy of individual well monitoring in determining the following:

TABLE 1

SUMMARY OF OPERATING CHARACTERISTICS OF
TYPICAL FLOW AND PRESSURE METERING DEVICES

Meter Type	Basis of Operation	Accuracy	Range	Comments
Flow Metering				
Pressure Differential Meters	Flow constriction	± 1% calibrated		Orifice - Low Price Low installation cost
Orifice Venturi Nozzle		± 2-3% uncalibrated		High head loss
Rotating Mechanical Meters	Volume of Flow			
Positive Displacement	Counts known volume	± 0.2%	20:1	Used in 1,000 to 30,000 bbl/day
Gear Oval Wheel Sliding Vane				
Turbine	Frequency of Pulses	Good-between 10 - 100% of range ± 1% if maintained	10:1	Not as accurate as positive displacement
Disc (wobble meter)	Chamber volumes	± 2%		Typical Flow Range Used from 100 to 5000 bbl/day
Pressure Metering				
Bourdon Guage (tube)	Pressure deflection of tube	± 3% or better		
Transducers	Pressure deflection on diaphragm	± 1% or better		

1. Leaks in the tubular goods of the wells;
2. Compliance with injection pressure limitations;
3. Compatibility of injection fluids with tubular goods and the injection formation; and
4. Injectivity of the well.

The process of evaluating whether inidividual well monitoring is comparable to manifold monitoring will consider only those parameters from the following list: (1) flow rate; (2) cumulative volume; (3) pressure; and (4) the nature of the injected fluid, which may impact the particular determination. For example, the nature of injected fluid whether monitored on an individual well or manifold basis, would not impact the determination of leaks in tubular goods. Therefore, only flow rate, cumulative volume and pressure would be used in evaluating the adequacy of manifold monitoring in determining leaks in tubular goods.

3.2 LEAKS IN TUBULAR GOODS OF WELL(S)

3.2.1 Individual Injection Well Monitoring

The detection of leaks in the tubular goods of an injection well potentially can be accomplished using both pressure and flow data at the well head. Indicators of leaks could be an unexplained increase in flow with a corresponding drop in pressure at only a single well in a field. These parameters can be used as indicators if formation pressure, assuming no leak, changes in a relatively uniform manner with similar responses from other injection wells in the field. If the formation is such that pressure and flow changes are formation related, then the use of these parameters may not provide a reliable indicator.

The detection of a leak using an individual well monitoring program depends to a large extent on the size of the leak and the accuracy of the pressure and flow meter. In a case where the change in pressure due to the leak is

10 pounds per square inch (psi) and the gauge is accurate to 50 psi, the pressure drop potentially could go unnoticed. Using Figure 8, it can be seen that for a gauge with a 5 percent accuracy operation at 1000 psi, a change in pressure would fall below the limits of the accuracy of the gauge and go undetected. Similarly, if the flow meter used were accurate to 50 barrels per day and the leak were 5 barrels per day, the change in flow rate might also go unnoticed. To be useful in detecting leaks, the flow meter, in particular, must have an accuracy such that it is capable of detecting flows equal to what would be considered a significant leak. Generally, accurate flow measurement is the best indicator of small leaks and will be discussed further in regard to manifold monitoring.

3.2.2 Manifold Monitoring

The use of manifold monitoring may present a handicap in detecting leaks in tubular goods of a well when compared to individual well monitoring. The reason for this handicap is twofold. First, with manifold monitoring, if a leak is detected, the location is unknown, since this method of monitoring only provides data on the system as a whole and not the individual wells. The second reason for this handicap lies in the potential ability of such a system to detect small changes in flow caused by a leak. For example, assume a system has 6 laterals coming off from a manifold with 1/6 the total assumed flow of 24,000 bbl/day going to each well. The flow meter used to measure flow to the manifold is assumed to have an accuracy at 24,000 bbl/day of approximately ±0.5 percent or ±122 bbl/day. The flow meters on a system with flow measurement at each well is assumed to have the same accuracy at 4000 bbl/day or ±20 bbl/day. If a leak of approximately 30 barrels per day of fluid were to develop, the larger meter on the manifold may not be able to detect it since 30 barrels per day is only 0.1 percent of the total flow. The smaller meter at each well should detect this flow rate change because of its accuracy at the lower flow range. For these systems to be comparable, the large meter would have to have an accuracy at the rated flow of 24,000 bbl/day to detect a flow of

30 bbl/day. This would require the manifold flow meter to have an accuracy of about ± 0.1 percent at the rated flow. An example plot of detectable flow rate changes for meters of various accuracies is given on Figure 7. Although Figure 7 does not extend out to the 24,000 bbl per day range, the data is linear and can be extrapolated to give the results described in the text.

Similarly, pressure changes as measured on the manifold would be so small for the example given above, that current technology potentially could not detect them. The reason for this is that small flow rate changes in an individual well would result in small pressure changes on the overall system.

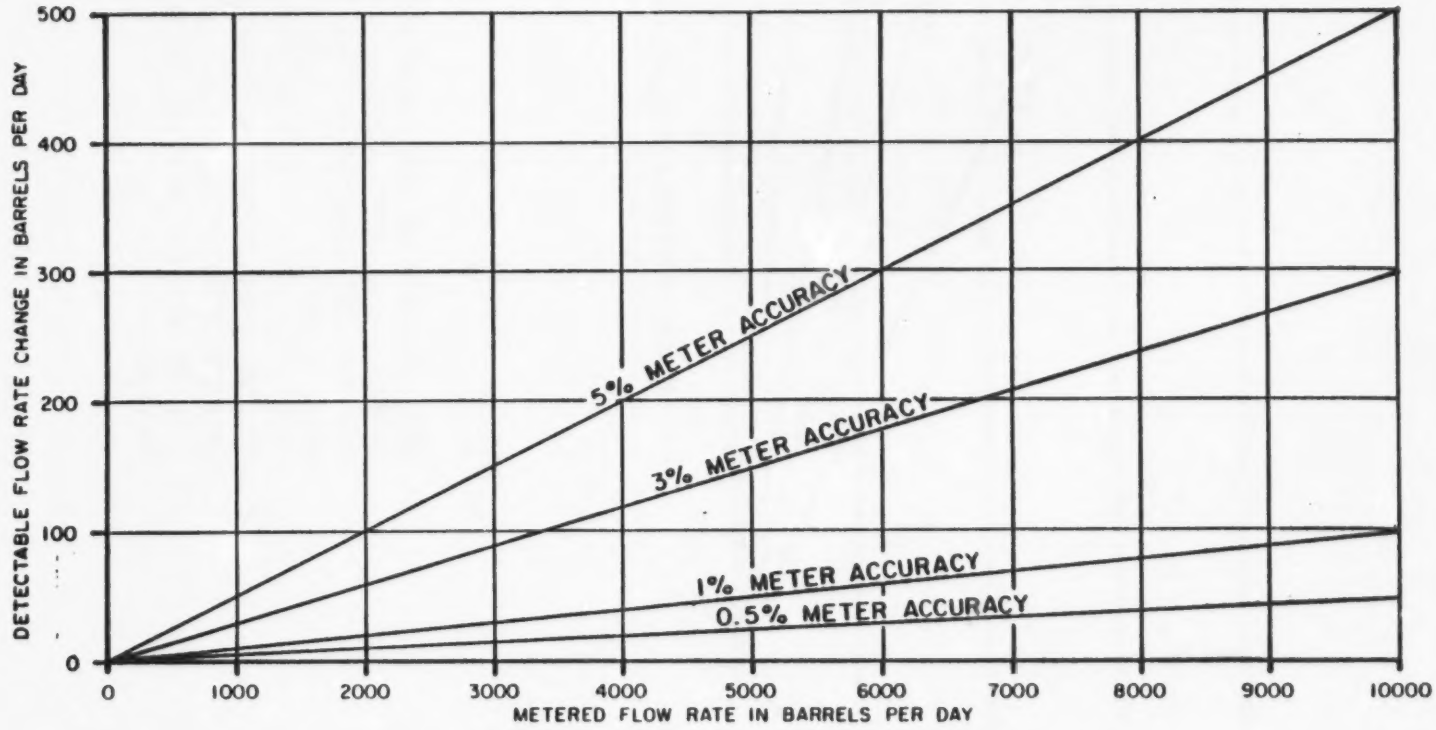
Head loss through the manifold system and laterals to each well is a function of the flow velocity to approximately the second power. If, for example, flow of 24,000 bbl/day were through a straight piece of 6-inch diameter steel pipe 2000 feet long, the head loss would be 62.6 feet of water or 27.1 psi. The loss through the same pipe for 24,030 bbl/day would be approximately 62.76 feet of water or 27.2 psi. A difference of 0.1 psi for a pressure gauge with an assumed range of 0 - 1000 psi and an accuracy at the rated pressure of ± 1.0 percent would be below detection limits. The gauge would be accurate to 5 psi if the pressure in the system were approximately 500 psi (500 psi x 1% = 5 psi). Figure 8 is a plot of detectable pressure changes versus system pressure at the gauge for various pressure gauge accuracies.

The manifold system is further complicated by pressure rises and drops across lateral branches. In dividing flow, a pressure rise occurs in the manifold after passing the lateral takeoff point (Figure 9B) due to decreased velocity. When moving from the manifold into the lateral, a pressure drop is generally noted (Figure 9A). In both cases, an overall drop in total head is noted due to friction losses at the branch for either path. The friction losses and pressure changes which are a function of

NOTES:

1. METER ACCURACY ASSUMED LINEAR OVER RANGE OF FLOW RATES. ACTUAL ACCURACY WILL VARY PARTICULARLY AT HIGH AND LOW ENDS OF RANGE. AMOUNT OF VARIABILITY FUNCTION OF PARTICULAR METER.

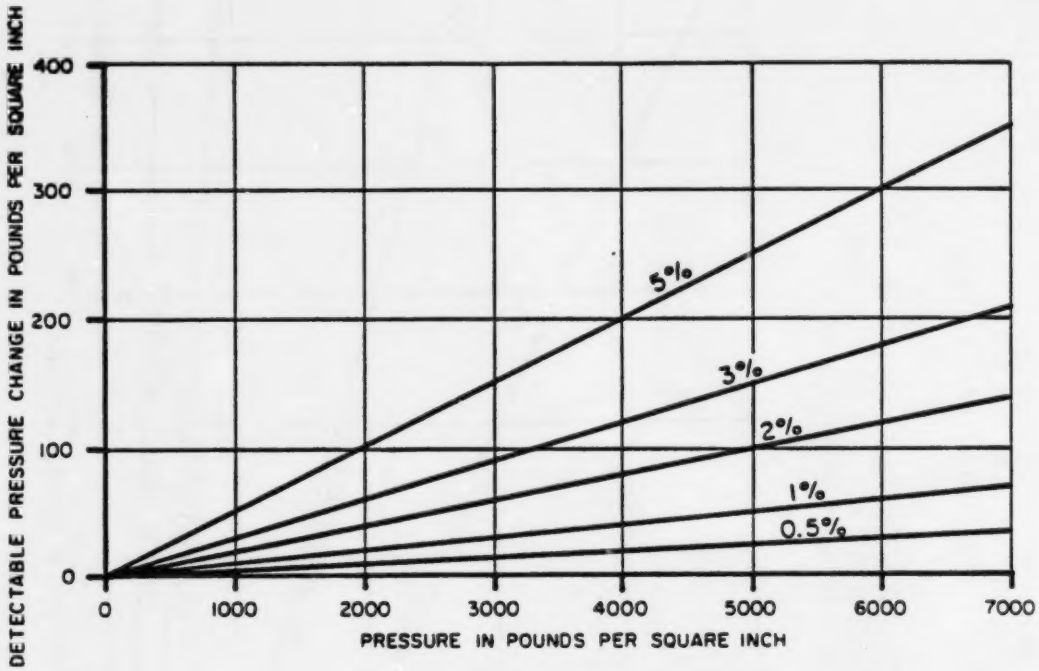
2. FOR FLOW RATE CHANGES TO BE DETECTABLE THE VALUE SHOULD BE ABOVE THE ACCURACY LINE FOR SELECTED METER. FOR 6000 BBL/DAY AT AN ACCURACY OF 5% FLOW CHANGE SHOULD BE GREATER THAN 300 BBL/DAY TO BE DETECTABLE.



LIMITS OF DETECTABLE FLOW RATE CHANGES FOR FLOW METERS OF VARIOUS ACCURACIES

FIG. 7

Woodward-Clyde Consultants



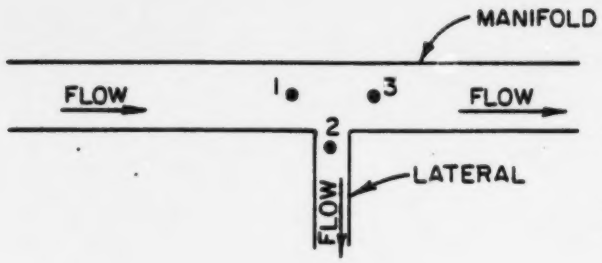
NOTES:

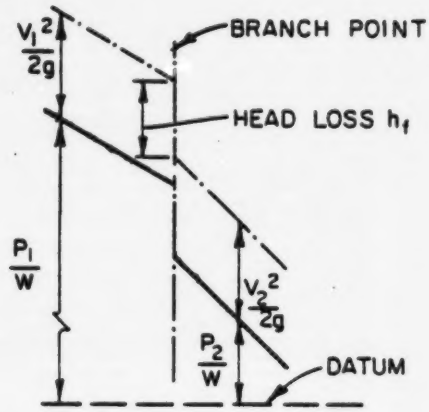
1. METER ACCURACY ASSUMED LINEAR OVER RANGE OF PRESSURES. METER ACCURACY MAY VARY OVER PRESSURE RANGE AND MAY VARY FROM METER TO METER.

2. PRESSURE CHANGES TO BE DETECTABLE SHOULD PLOT ABOVE THE METER ACCURACY LINE FOR SPECIFIC METER AT THE MEASURED PRESSURE.

LIMITS OF DETECTABLE PRESSURE CHANGES FOR PRESSURE GAGES OF VARIOUS ACCURACIES

FIG. 8





(A) ENERGY DIAGRAM FROM POINT 1 TO 2

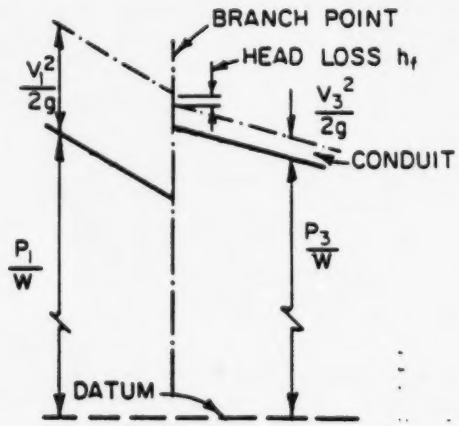
LEGEND

P_1, P_2 AND P_3 = PRESSURE IN PIPE

V_1, V_2 AND V_3 = FLOW VELOCITY

W = UNIT WEIGHT OF FLOWING FLUID

g = ACCELERATION DUE TO GRAVITY



(B) ENERGY DIAGRAM FROM 1 TO 3

ENERGY DIAGRAM ACROSS A FLOW DIVIDING TEE

FIG. 9

flow to each branch can not be estimated with any degree of accuracy since the distribution of flow cannot be estimated accurately. The conclusion to be drawn from the example is that large pressure changes due to large changes in flow are needed to be detectable given the economics and current practice in pressure metering. Pressure data from an individual well or manifold monitoring system by itself would be of very limited value in detecting small leaks.

Although less likely to occur, the potential does exist for a single well to plug and a leak to develop in another. In a situation such as this, given the right set of circumstances, a very significant leak could occur in conjunction with the plugging of another well and both might go undetected on a system where manifold monitoring is used.

Another possibility is that a break or leak occurs in a buried lateral or section of manifold. The leak again could go undetected if small enough compared to the accuracy of the manifold monitoring flow meter. The chances of discovering a leak such as this with individual well monitoring is only possible if a manifold flow meter is also used as a master system meter to monitor the whole system. In this case, the sum of the flows to each would be less than the discharge measured at the master meter indicating the potential existence of a leak.

In summary, the individual well monitoring system is only of marginal adequacy in its ability to detect leaks in the tubular goods of a well. Small leaks may in many cases go undetected. The manifold monitoring system is even less likely to detect a leak. If a leak is detected from manifold monitoring, its location is not known.

3.3 COMPLIANCE WITH INJECTION PRESSURE LIMITATIONS

3.3.1 Individual Well Monitoring

As discussed previously, when individual wells are monitored the pressure and flow are measured at the well head, thus making verification of compliance with injection formation pressure at the well bore relatively straight-forward. The adequacy of this method is only limited to the accuracy of the pressure and flow meters at the well head.

Assuming pressure and flow data at the well head are given, the pressure at the injection formation can be computed using simple hydraulic techniques. For purpose of our discussion regarding viability of manifold monitoring as compared to individual well monitoring, we have assumed that, in either case, if pressure and flow could be estimated or measured at the well head, pressure at the injection formation could also be easily estimated. If these data could not be measured or estimated at the well head, then pressure and flow could not be estimated at the injection formation. Therefore, the following discussion compares pressure as measured or estimated at the well head and not at the injection formation.

3.3.2 Manifold Monitoring

Measurement of pressure and flow rate on a manifold upstream of the well heads provides no direct means of estimating pressure at the well heads. These data do provide the needed input for making a very approximate indirect estimate of pressure at the individual well heads. Pressure changes through the system are impacted by many factors including pipe losses and minor losses (fittings, valves, etc.) which are all a function of flow distribution.

If the total (available) energy at the manifold monitoring point were converted to pressure energy (pressure head), this would represent the

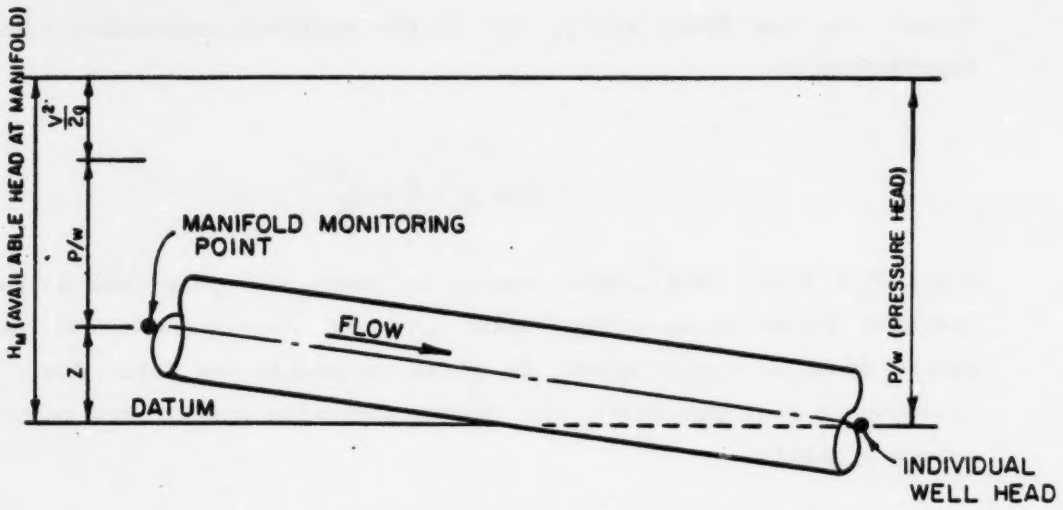
maximum pressure which could exist at an individual well head. As shown on Figure 10A, the total energy (H) at the manifold monitoring point can be represented as:

$$H = Z + \frac{P}{w} + \frac{V^2}{2g}$$

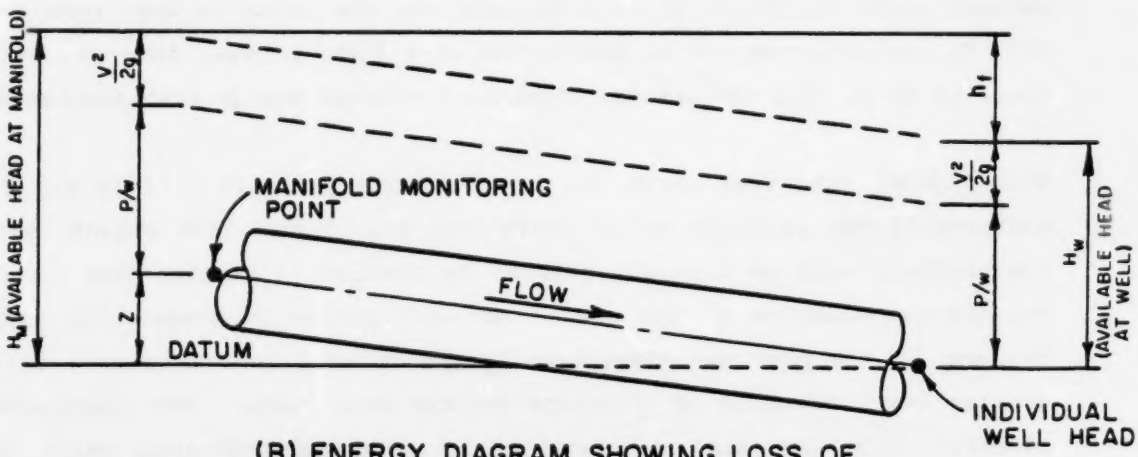
where H = total (available) energy in feet, Z = potential energy due to position above an arbitrary datum in feet, P = pressure in pounds per square foot, w = unit weight of water in pounds per cubic foot, V = flow velocity in feet per second and g = acceleration due to gravity in feet per second squared.

For purposes of this example, it was assumed that H at the monitoring point would be converted to an equivalent amount of pressure head P/w at the individual well head. This in fact would not be the case, since, as can be seen in Figure 10B, the total head available in a flowing pipe decreases in the downstream direction due to headlosses (h_f) caused by friction. The example given in Figure 10 is simplistic but the point is that less energy will be available as you go downstream in a flowing pipe, thus the maximum pressure which could be assumed equal to available energy also decreases.

The approach discussed above for approximating pressure will in all cases overpredict the pressure at an individual well head. The amount that it overpredicts will be directly related to headloss (friction loss) through the various branches of the system and differences in topographic relief. The age of the pipe may significantly affect head loss resulting in even greater overprediction of pressure at the well head. The magnitude of overprediction may also be impacted by pressure increases which occur across branch points in the system. These pressure increases are functions of flow distribution. Headloss is a function of flow velocity in each pipe, which is directly related to the distribution of flow through the system.



(A) ENERGY DIAGRAM ASSUMING AVAILABLE HEAD AT MANIFOLD CONVERTED TO PRESSURE HEAD AT WELL



(B) ENERGY DIAGRAM SHOWING LOSS OF AVAILABLE HEAD BETWEEN MANIFOLD AND WELL

LEGEND

V = FLOW VELOCITY

P = PRESSURE IN PIPE

h_f = FRICTION HEAD LOSS

w = UNIT WEIGHT OF FLOWING FLUID

Z = DISTANCE ABOVE DATUM

g = ACCELERATION DUE TO GRAVITY

NOTE:

1. TYPICALLY $\frac{P}{w} \gg \frac{V^2}{2g} + Z + h_f$

ASSUMED AND ACTUAL ENERGY DIAGRAM FOR WELL HEAD PRESSURE USING MANIFOLD PRESSURE

FIG. 10

In most cases, the portion of total head made up by kinetic energy ($V^2/2g$) would be relatively small. Typically, velocities in injection systems range from about 3 to 10 feet per second (ft/sec). At a flow velocity of 10 ft/sec, the portion of total head made up of kinetic energy would be approximately 1.55 feet or about 0.67 psi.

The portion of total head lost to friction in many cases is relatively small. In the manifold monitoring example, Section 3.3.2, previously discussed, velocity was about 7.8 ft/sec, with a friction loss of about 62.6 feet or 27.1 psi. The velocity of 7.8 ft/sec would generally be considered as slightly above average, thus the headloss over the 2000 feet of pipe might also be considered slightly above average. If the maximum flow path were about 2 miles, the headloss would be about 143 psi. Assuming the pressure gauge on the manifold was indicating a typical pressure of about 3500 psi, the maximum percent difference between the manifold gauge and the well head would be 4 percent. Although the pressure cannot be estimated directly, its maximum value based on the manifold pressure, may only be an overprediction by as much as 7 or 8 percent. The higher the system pressure, at the same headloss, the smaller the percent of overprediction. At a system pressure of 5000 psi, the estimated well head pressure based on a manifold pressure measurement would only be about 3 percent for a headloss of 143 psi.

3.4 WELL INJECTIVITY

The injectivity of the well is the ability of the well to discharge injection fluid to the surrounding formation. Typically, if a well has high injectivity, the injection formation readily accepts injection fluids. Based on this definition of injectivity, the elements of manifold and individual well monitoring which are relevant in its determination include injection pressure and flow rate. The nature of the injected fluid may also have an impact on injectivity; however, for purposes of this document, water is assumed to be the injection fluid.

3.4.1 Individual Well Monitoring

Measurement of pressure and flow at the well head should be relatively good indicators of well injectivity. The adequacy of these measurements in determining well injectivity is related to the accuracy of the pressure and flow meters. Accurate measurement of flow at the well head is the most important input to estimating changes in injectivity. Overall injectivity may be adequately determined using individual well head monitoring.

3.4.2 Manifold Monitoring

The use of pressure and flow data from manifold monitoring systems would appear not to be viable on an individual well basis. These data would be viable for use in estimating overall field injectivity but of only marginal value in assessing an individual well.

The major problem with manifold monitoring as it relates to injectivity is that the injection rate to individual wells is not known with any degree of certainty. Since injectivity is relatively sensitive to injection rate, the inability to measure or estimate flow to individual wells makes determination of injectivity virtually impossible accept on a field wide basis.

Additionally, since flow to individual wells is not accurately known, the possibility exists that total field injectivity estimates are based on less than all of the wells in the fields. For example, if one well in a field with four is plugged, the injectivity may appear relatively small but in fact it could be substantially larger.

The injectivity of a four well system operating with one well plugged would appear to have only 75 percent of the actual field injectivity. This would occur due to the added flow into each of the three unplugged wells. The assumed flow into each well would be on 75 percent of actual, thus

injectivity based on this flow and increased pressure would indicate lower injectivity.

The use of manifold monitoring would provide similar information on a project/field basis but little would be known about individual well operation. This is due to the inability to estimate with any degree of accuracy the flow and pressure to individual wells. The injectivity of an individual well may be estimated by shutting off flow to all but one well and measuring flow and pressure with the manifold monitoring system.

3.5 COMPATIBILITY OF INJECTION FLUIDS WITH TUBULAR GOODS AND INJECTION FORMATION

The compatibility of the injection fluid with tubular goods and the injection formation is defined to mean the chemical and physical reaction of each to one another. Chemical compatibility is more specifically defined as the reaction potential between injected fluids and the tubular goods of the well or the injection formation. The physical compatibility of the injection fluid is further defined as the erosion potential (physical decomposition) with regard to tubular goods of the well and the potential plugging properties with regard to the injection formation.

3.5.1 Individual Well Monitoring

Individual well monitoring appears to be adequate in determining the potential chemical and physical compatibility of injection fluids with the tubular goods of the well and the injection formation. The chemical compatibility of injected fluid would have to be evaluated based on analysis of samples taken of the injection fluid. The location of the sampling point should have little impact on the chemical analysis since no change in the injection fluid is anticipated as it is pumped through the system. If the injected fluids react in such a way with formation material so as to reduce injectivity of the well, the ability to detect such a

change is based on the accuracy of the flow and pressure metering devices. The same holds true with regard to physical compatibility of injection fluids with the formation. If plugging due to suspended material occurs, the detectability is related to the accuracy of the flow and pressure metering devices and the extent of the problem.

3.5.2 Manifold Monitoring

The primary difference between the manifold monitoring and individual well monitoring as it relates to determining the compatibility of injection fluid with tubular goods of the well or the injection formation, is the ability to detect changes in pressure and flow rate to each well. If the injected fluid reacts similarly in each well, the manifold monitoring system should be adequate. However, if problems occur on an individual well basis, detection may be difficult for the reasons discussed previously. The location of a sampling point should have no effect on chemical analysis for determining compatibility.

4.0 VALIDITY AND SENSITIVITY OF MANIFOLD DATA

4.1 INTRODUCTION

The following section discusses the limitations of size and extent of the manifold on the validity and sensitivity of data obtained by manifold monitoring particularly in light of field size, configuration and topographical variation.

The size of the manifold is defined as the inside dimensions of the manifold pipe. Extent of the manifold is defined as overall length of the manifold system from the injection pump to the various injection well heads. Field size refers to the overall dimensions of the recoverable oil bearing formation. The configuration of the field refers to the general three dimensional shape of the oil bearing formation and topographical

variation refers to the elevation of land surface above the oil bearing formation.

The validity and sensitivity of data obtained from manifold monitoring is evaluated based on its representation of conditions at any individual well head which, if known, can be, by using simple hydraulic techniques, used to estimate conditions at the injection formation.

4.2 FLOW DATA

4.2.1 Validity

Flow data obtained from a manifold monitoring system is valid as an indicator of injection rates or volumes on a project/field basis. They would not in any way be an indicator of the proportion of the total project flow that may be going to any individual well. The size and extent of the manifold should not impact the operation of the selected flow meter as an indicator of total field injection rate. The larger the manifold, generally, the larger the injection rates. The extent of the manifold indicates the general size of the field but should have no impact on the validity of flow measurement. Field configuration and topography of the ground surface of the field would not impact validity of flow measurement.

4.2.2 Sensitivity

The sensitivity of the flow data obtained from a manifold monitoring system would only be affected by the overall project injection rate. The larger the injection rate, the larger the meter capacity. As meter capacity increases, the sensitivity of the meter to small changes in flow is diminished. The sensitivity of the meter, in general, would not be reduced by manifold size, extent, field size, configuration and topographical variation unless it was related to injection fluid flow rate.

4.3 INJECTION PRESSURE

4.3.1 Validity

The pressure measured at the manifold monitoring point is not valid as injection pressure at the individual well heads. As discussed previously, pressure at the manifold may be relatively close to the actual pressure at the injection well head but the difference is a function of headloss which in turn is a function of flow distribution within the system. This difference may also be a function of elevation difference between the manifold monitoring point and various injection wells. Since elevation differences would remain constant, they can easily be accounted for and they should not limit manifold size or extent.

The manifold extent significantly impacts the approximate validity of the pressure measured at the manifold as an indicator of injection pressure. The longer the manifold system, the greater the total headloss through the system. Since headloss is a function of flow distribution (velocity in individual pipes) and flow distribution is not known with any degree of accuracy throughout the system, headlosses are also not known. The headloss from the manifold to the various injection wells increases with manifold extent and age of pipes making the potential greater for substantial differences in pressure between these two points.

4.3.2 Sensitivity

The size of the manifold does not impact the sensitivity of the pressure measurement made there. The extent of the manifold generally has no impact on sensitivity of pressure measurements. If the manifold system were to become large enough to require a significantly higher range pressure gauge then some sensitivity may be lost. This situation is highly unlikely due to additional pumping cost. The piping system would be designed to minimize pumping costs.

Under most normal operating conditions, the impact of field size, configuration and topographical variation would not impact manifold size or extent limitation as they relate to validity and sensitivity of pressure data measured on the manifold.

4.4 NATURE OF INJECTED FLUID

Since the nature of injected fluids is not expected to change from point to point in the system, the impact of manifold size and extent on validity and sensitivity of data obtained at the manifold is expected to be insignificant.

5.0 EVALUATION CRITERIA

5.1 INTRODUCTION

The following section provides evaluation criteria for use by EPA personnel in evaluating whether manifold monitoring programs are comparable to an individual injection well monitoring program for the same field. The evaluation criteria presented in this section are based on the discussions in Sections 3 and 4 of this report which are summarized below:

(1) Manifold monitoring is of limited use in detecting leaks in the tubular goods of the well. There are several reasons for this. First, leaks cannot be located since this method of monitoring provides data only on the system as a whole and not the individual wells. Secondly, the degree of accuracy of flow measurements allows for detection of only large leaks. Third, pressure changes would have to be great enough to detect. Other conditions of well plugging and pipe breakage also make manifold monitoring of limited viability in detecting anything but large leaks. The individual well monitoring system would potentially have better capabilities of detecting smaller leaks manifested through pressure and flow rate changes.

In summary, manifold monitoring systems would generally be less sensitive to pressure and flow changes than individual well monitoring systems. As a result, this level of sensitivity would make manifold monitoring less likely to detect leaks identified by individual well monitoring on the same systems but potentially able to detect large leaks. It is important to note that the size of the leak with respect to the specific system is a key element in evaluating whether either an individual well or manifold monitoring system is capable of detecting it through pressure and flow changes.

(2) Manifold monitoring is of limited use in determining individual well injection pressures. The pressure on the manifold provides no direct means of estimating pressure at the individual well heads. A determination must be made, to base the pressure for compliance purposes on the pressure at the individual well or to base the pressure on the overall field limit, measured at the manifold monitoring point. The operating and maximum injection pressures at the manifold monitoring system could be set by considering all the headloss factors in the manifold system.

(3) Well injectivity for a manifold monitoring system cannot be estimated with any degree of accuracy, but can only provide an estimate of overall field injectivity. A manifold system cannot measure injection rate to individual wells, and the possibility exists that total field injectivity may be based on less than all the wells in the field. However, injectivity tests may be performed on individual wells in a manifold system if wells can be shut in separately.

(4) Detection of compatibility problems between the injection fluid and the tubular goods and/or the injection formation may be difficult because of the ability to detect changes in pressure and flow rate to each well. This is especially true if problems do not occur similarly in each well. However, the location of sampling points to determine

the compatibility of injection fluid with tubular goods and the injection formation is not critical in a manifold monitoring system.

(5) Flow data from a manifold monitoring system are valid as indications of injection rates or volumes on a project/field basis. The data collected will not be an indicator of the proportion of the total project flow going to any individual well. Size, extent, field configuration and topography would not affect the validity of flow measurements.

(6) The sensitivity of the flow data obtained from a manifold monitoring system is affected by the overall project injection rate (flow). As meter capacity increases, sensitivity of the meter to small changes in flow decreases.

The sensitivity of the meter, in general, would not be reduced by manifold size, length of the manifold system, field size, the shape of the oil formation or topographical variation.

(7) Injection pressure measured at the manifold monitoring point is not accurate as an indicator of injection pressure at the individual well heads. Pressure at the well head is a function of injection pump head minus headloss through the system, and the longer the manifold, the greater the total headloss through the system. Therefore, there could be differences in pressure between the manifold monitoring point and the individual well heads. However, this difference compared with a typical injection system pressure would be small.

(8) The sensitivity of pressure measurement is not affected by the size or length of the manifold. Sensitivity of a pressure gauge would be reduced if a higher pressure were required because of system injection requirements.

(9) The sensitivity and validity of data on the nature of injected fluids are not significantly affected by manifold size and length.

For purposes of this document, a comparable manifold monitoring system is one which has the same degree of adequacy as the alternative individual well monitoring system. The question of adequacy is beyond the scope of this document. If the individual well monitoring systems, based on current technology and economics, have been considered and deemed inadequate for determining various parameters, a comparable manifold system would also have the same inadequacy. For example, if an individual well monitoring system had an accuracy of ±0.5 percent of the rated flow but would not be adequate in determining a leak under normal operating conditions, then a manifold system with the same accuracy would also be inadequate but potentially comparable. Normal operating condition assumes regular operating personnel following routine procedures. If an individual system is capable of detecting leaks with additional personnel and alternate procedures, the operating condition could not be considered normal and the question of whether two systems are comparable could not be made on this basis.

5.2 APPROACH TO CRITERIA DEVELOPMENT

The development of criteria for evaluating proposed programs requires that magnitudes be assigned to various measured parameters by the EPA in order to clearly define adequacy. Also, the definition of minimum requirements for an individual system are critical in determining adequacy of that system to perform a particular monitoring operation at a specific level of detail. If individual systems with low accuracy levels are allowed that are inadequate in determining even relatively large leaks, then the requirements for a comparable manifold system will be significantly less stringent.

The following discussion of evaluative criteria provides a qualitative, and to the degree possible, quantitative approach for examining individual well

meter adequacy and their comparison with proposed manifold monitoring systems.

The initial step in examining a manifold monitoring system would be to define the minimum acceptable program for an individual monitoring system. Once the minimum acceptable program for the individual system has been clearly defined, the adequacy of that system to provide necessary data for determining leaks, for instance, can be evaluated. Based on this evaluation, the proposed manifold system can be examined. Listed below is the evaluative procedure developed as part of this study for individual and manifold monitoring systems.

The minimum requirements for individual well metering systems would be based on criteria established by the regulating agency. The adequacy of the individual well metering system would be evaluated based on the minimum requirements as follows:

(1) Leaks in Tubular Goods of the Well. The flow monitoring device should be of the required accuracy to detect a specific lower limit of incremental changes in flow. The lower limit of incremental changes in flow would be specified by the regulatory agency.

(2) Compliance with Injection Pressure. The pressure meter should be of the required pressure range to measure anticipated pressure. The accuracy of the gauge should be such that pressure at the well head could not exceed regulatory agency limitation by a specified amount without detection.

(3) Injectivity of the Well. The minimum requirement for pressure and flow metering as a means of determining well injectivity would be based on regulatory agency guidelines. The metering devices selected and their accuracies should be within these minimum requirements.

(4) Compatibility of Injection Fluid With Tubular Goods and the Injection Formation. The sampling point may be anywhere in the system; no anticipated impact on results is expected.

The comparison of a proposed manifold monitoring system with an individual well monitoring system would be as follows:

(1) Leaks in Tubular Goods of the Well(s). Based on the requirements established for an individual well described previously, a flow meter selected to monitor a manifold would have to have the accuracy to detect changes in flow of the same magnitude. If the metering device were able to detect flow rate changes of the same magnitude, then it would be considered comparable.

(2) Compliance with Injection Pressure Limitations. The manifold pressure monitoring system cannot be used to estimate well head injection pressure since information on flow distribution through the system is not available. However, if compliance is based on a pressure head at an individual well assumed equal to the total available head at the manifold monitoring point, the actual well head pressure will be less. If the injection pressure limitations are for the overall field rather than discrete injection points, the manifold system can be utilized; however, if the injection pressure limitations are for discrete points, the manifold system cannot, with any degree of accuracy, determine individual well injection pressures.

(3) Injectivity of the Well. The manifold system will not provide any meaningful data on the injectivity of a well, only the apparent injectivity of the field.

(4) Compatibility of Injection Fluid with Tubular Goods and the Injection Formation. As discussed in the text, the location of the sampling point for individual well or manifold type systems would have no impact on determining compatibility. The systems should be the same in either case.

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APPENDIX A

ADDITIONAL FLOW MEASURING DEVICES

A-1 INTRODUCTION

In addition to the more common differential and rotating mechanical type meters, numerous variation to these meters as well as completely different meters have been developed to accomodate special application. In some cases, existing meters were modified to reduce headloss, in others, modifications addressed special problems associated with the fluid being measured such as suspended sediment. The following section describes and discusses an additional assortment of pressure differential and rotating mechanical meters which potentially could find application in all enhanced recovery injection systems.

A-2 PRESSURE DIFFERENTIAL METERS

The three basic pressure differential meters (orifice, venturi and nozzle) have seen many modifications in an effort to improve operating characteristics. The opening of an orifice has in some cases been moved from its concentric location in a pipe to various positions as shown on Figure A-1-a and b. These locations allow the passage of solids through the meter and prevent the accumulation of solids upstream of the meter which could affect performance.

The headlosses across the orifice type meter are generally recognized as the highest of the pressure differential type meters with the smallest installation space requirement. The venturi type meter has the smallest headloss with the largest installation space requirement. To reduce the required installation space of the venturi, the venturi nozzle was developed (Figure A-2). This meter requires less installation space than the standard venturi; however, the nozzle type entrance results in higher meter headloss.

Modifications to the standard venturi have been made to reduce its already low headloss characteristics. Two devices include the Dall tube and the Universal venturi. The devices are shown on Figure A-3. Other pressure differential devices which are modifications to the more common devices such as the orifice and venturi, are the Dall orifice and the Epiflo (Figure A-4).

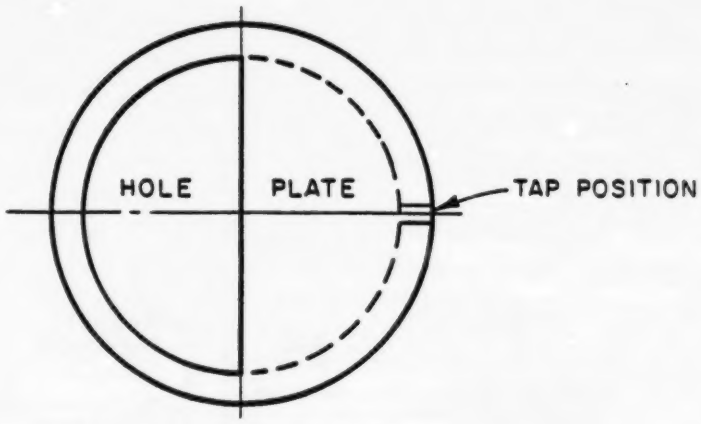
A-3 ROTATING MECHANICAL METERS

The number of rotating mechanical meters, other than the positive displacement and turbine type, is considerable. A number of these meters are discussed below with regard to configuration and operation.

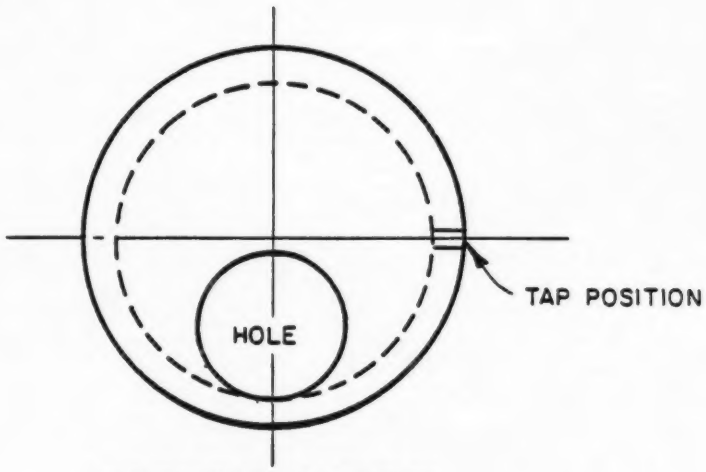
The constrained-vortex meter is sometimes referred to as a vortex meter. The vortex meter consists of a large, freely spinning rotor mounted such that its axis is perpendicular to the flow path, which is eccentrically placed in a bulge in the pipe. A typical schematic for vortex type meter is shown on Figure A-5a. The vortex meter is generally cheaper but less accurate than the positive displacement and turbine meters.

The Hoverflo is described as a bearingless type transmitter. The Hoverflo is like a double rotameter with two floats joined together by a rigid shaft and each taking half the main flow. When flow is passing, the rotor takes up a central position which is one of stable equilibrium and thus it floats without metal-to-metal contact. A magnetic pick-up provides a direct digital output. A schematic of the Hoverflo meter is given on Figure A-5b.

Another type of rotating flow meter is the angled propeller meter. This type of meter is inserted into the flow section with a propeller of sufficient size to be affected by practically the whole flow passing. The bearings of such a meter are located outside the flow stream making them less likely to be susceptible to damage. A typical schematic of an angled propeller meter is shown on Figure A-6.



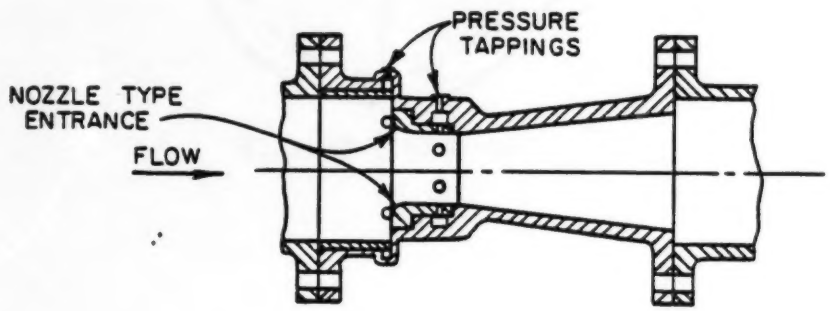
(a) CHORD ORIFICE



(b) ECCENTRIC ORIFICE

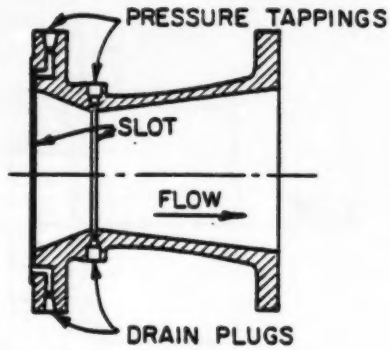
VARIATION OF
ORIFICE TYPE METER

FIG. A-1

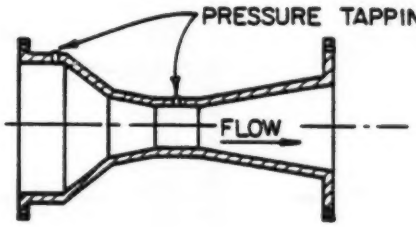


VENTURI NOZZLE

FIG. A-2



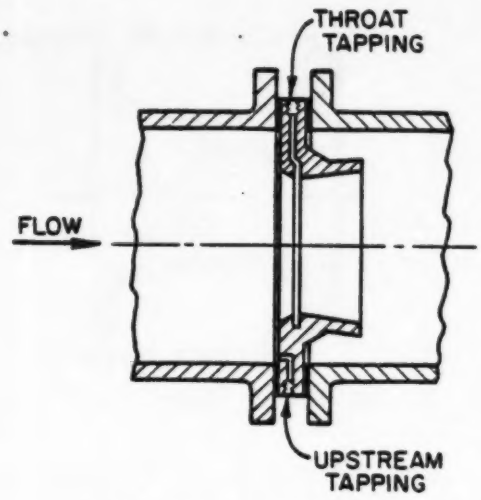
(a) 'DALL' TUBE



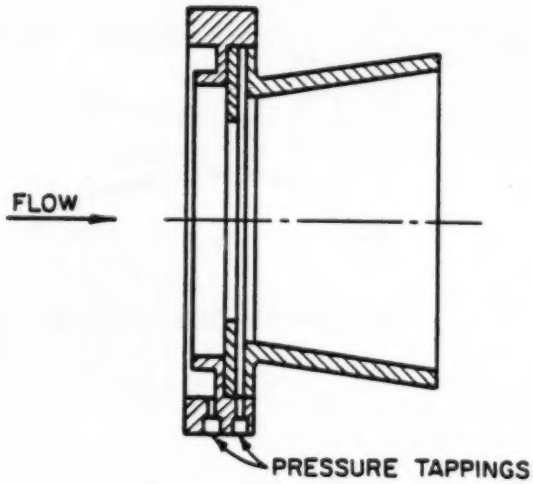
(b) 'UNIVERSAL' VENTURI

LOW HEADLOSS
PRESSURE DIFFERENTIAL FLOW METERS

FIG. A-3



(a) 'DALL' ORIFICE

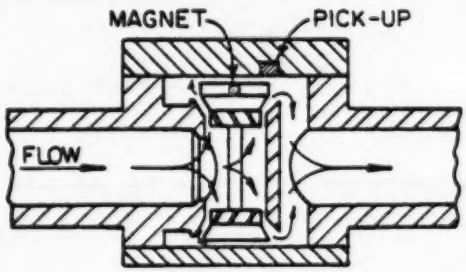


(b) THE 'EPIFLO'

LOW HEADLOSS
ORIFICE TYPE FLOW METERS

FIG. A-4

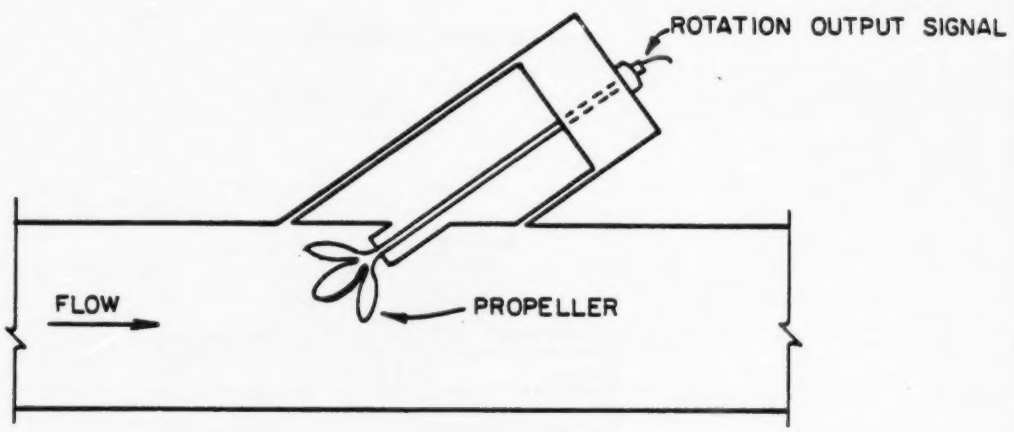
(a) VORTEX METER



(b) HOVERFLO METER

ROTATING MECHANICAL
FLOW METERS

FIG. A-5



ANGLED PROPELLER
TYPE FLOWMETER

FIG. A-6